

Commonwealth of Kentucky
Environmental and Public Protection Cabinet
Department for Environmental Protection
Division for Air Quality

Statement of Basis

Title V Draft Permit, No. V-07-017

Cash Creek Generation, LLC
Cash Creek Generating Station

Henderson, KY

Source I.D. #: 21-101-00134
Source A.I. #: 40285
Activity I.D. #: APE20060001

Reviewer: Herbert Campbell

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Division of Air Quality

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1. PROJECT SUMMARY

The proposed facility will be located southwest of Owensboro, Kentucky, on Kentucky State Highway 1078 in Henderson County (37:42:10 N Latitude, 87:24:50 W Longitude). On May 4, 2006, Cash Creek Generation, L.L.C (Cash Creek) filed an application for a PSD/Title V air permit to construct a nominal 770 megawatt (MW) electric generating facility using Integrated Gasification Combined Cycle (IGCC) technology. On June 19, 2006, the Division issued a notice of deficiency. The response was filed on August 9, 2006, and included revised application forms. A second notice of deficiency was issued on September 20 and responses were on October 12 and November 11, 2006. Application was declared complete on March 29, 2007.

The IGCC process will use coal to produce synthesis gas (syngas) as the primary fuel (natural gas is a secondary fuel) to fire two, GE7FB series combustion turbines in combination with a heat recovery steam generating (HRSG) unit and a steam turbine to produce a nominal 770 MW (net output of 630 MW) of electricity. The syngas mainly consists of hydrogen gas and carbon monoxide. The two GE combustion turbines will operate in combined cycle mode, such that heat from the combustion turbines will be recovered in a heat recovery steam generator (HRSG) and steam turbine unit which also produces an additional 306 MW of electricity. The balance of the facility includes additional equipment necessary to start-up, maintain and operate the facility and which consumes approximately 140 MW for a net output of 630 MW of electricity to the grid.

This permit authorizes up to three gasifiers that may be constructed. The gasifiers will operate using the GE (formerly Chevron Texaco) oxygen-blown, entrained flow process. This process includes coal slurry and oxygen feed systems, gasifier reaction chambers, and syngas cooling.

Primary operations include:

- coal supply and storage
- coal grinding and slurry preparation
- air separation
- gasification
- syngas cleaning and sulfur recovery
- power generation

Each of these operations are summarized from the application below.

1.1 Coal Supply and Storage

The primary coal supply is expected be provided by the Patriot Coal Company, which operates an existing underground and surface mining and processing operation adjacent to the Cash Creek location. The coal will be delivered by a conveyor from the mine to an onsite receiving transfer-house. The coal is then transferred to a second 42-inch conveyor and transported to a second transfer house. This second transfer house directs the coal to long-term storage (90,000 ton capacity) or feeds it directly to the grinding and slurry preparation system. Coal may also be supplied by barge from other coal sources. Coal received by barge will be offloaded and transported by a conveyor to the receiving transfer-house.

1.2 Coal Grinding and Slurry Preparation

The grinding and slurry preparation system is designed to process coal based on a maximum rate of 800 tons per hour. Coal is transferred from the supply belt to a weight feeder that meters coal into a rod mill, which contains steel rods that crush the coal as the mill rotates at a constant speed. Rotation of the mill also facilitates blending of water and coal to produce fuel slurry. Process water is used in the mill with fresh makeup water. Using process water allows entrained coal and slag fines to be recycled in the fuel slurry. The slurry exits the mill through a coarse trammel screen into an agitated discharge tank. Slurry is then pumped to the top of the run tank. Before entering the tank it is screened a final time to remove any oversize contaminants or coal that might damage the gasifier slurry feed pump. Slurry storage tanks are continuously agitated to prevent plugging and maintain the concentration of the slurry. Slurry flows by gravity to the suction of the gasifier feed pump for transport to the gasifier feed injector.

1.3 Air Separation

In the air separation block, air is cryogenically separated into oxygen and nitrogen. The oxygen is mixed with the coal slurry as the fuel feed to the gasification block. The nitrogen is used in the power block to lower gas turbine temperature and reduce NO_x emissions.

The main air compressor supplies compressed ambient air to a temperature swing absorption system to remove moisture and carbon dioxide, which is necessary to prevent freezing. Dry air is then routed to the main heat exchanger of the cryogenic section, where the air is cooled prior to entering distillation columns. Refrigeration for the separation process is supplied by a compander, using liquid nitrogen. The cryogenic distillation occurs in two columns, one operating at elevated pressure and the other at reduced pressure.

Diluent nitrogen is supplied to the combustion turbines by a multistage compressor. Similarly, high-pressure oxygen is needed for the gasifier feed and is supplied by a separate multistage compressor. Small amounts of low-pressure oxygen and nitrogen gases are also needed for other operations at the facility including the scrubbing operation. Withdrawing the gases prior to entering the compressors provides these low-pressure gases. Any impure nitrogen may be used as purge gas for the gasifiers.

1.4 Gasification

The gasifier block uses coal slurry/oxygen feedstock to produce syngas with a heating value of approximately 250 Btu/scf. The gasifier block will have two or three gasification units. Each unit will be designed to produce 50% of the syngas required when operating at maximum load.

Fuel is fed to the gasifiers through a process feed injector, which is designed to mix the coal slurry and oxygen and optimize dispersion into the gasifier. The three gasifiers, operating in an oxygen deficient atmosphere, are designed to operate at extremely high pressure and at temperatures between 2300° and 2700° F. These conditions in the gasifier promote reactions which produce three major products: syngas, fine slag, and a coarse vitreous slag.

As the syngas exits the gasifier it passes through a radiant syngas cooler that produces high-pressure steam and increases efficiency and reliability by recapturing up to 15% of the fuel's heating value. Prior to leaving the gasifier, syngas passes over and through a water pool located at the bottom of the unit that enhances collection of the entrained slag.

The syngas produced in the gasifiers is rich in hydrogen, carbon monoxide, water vapor, and carbon dioxide. There are also lesser amounts of hydrogen sulfide, carbonyl sulfide, methane, argon, nitrogen, VOCs, acid gas and other trace components. Further processing is required to remove impurities.

Fine slag comprises unreactive mineral compounds and fuel particles that are not completely gasified (unburned carbon). This material is carried from the gasifier with the exiting syngas and must be removed prior to entering the acid gas removal system. The syngas is scrubbed with water to remove entrained particulates. The dirty or "black" scrubbing water is flashed to lower temperature and pressure and concentrated in the fine slag handling section. This concentrated slurry is then recycled to the gasification section.

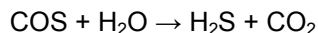
Slag is the mineral and ash matter that does not convert to syngas and is too heavy to be transported by the exiting syngas. A portion of this material melts in the high temperatures of the gasifier and flows to the bottom of the gasifier. It is removed from the gasifier through a lock-hopper. The slag is then transported to the slag handling operations. The slag is dewatered and transported by truck for sale as a by-product or to onsite landfills for storage. The slag ultimately solidifies into a stable glassy frit with very small amounts of residual carbon.

1.5 Syngas Cleaning

The syngas is scrubbed to remove particulates, treated to remove mercury and then enters an acid removal process. The acid removal stage removes sulfur compounds and produces molten elemental sulfur as a by-product.

The syngas passes through a multistage scrubbing process. This provides contact scrubbing with water and further removes entrained fine slag (flyash) from the syngas. It is during this scrubbing step that hydrogen chloride (HCl) is removed. The saturated syngas exiting the scrubber is then sent to the carbonyl sulfide (COS) hydrolysis reactor.

A small percentage of the coal slurry is converted to COS during the gasification process. The acid removal system is unable to remove COS from the syngas, so it must be converted to a form that can be moved to avoid a significant increase in sulfur dioxide (SO₂) emissions from the combustion turbines. Using a superheater followed by a catalyst reactor, conversion of COS to hydrogen sulfide (H₂S) is possible by the following chemical reaction:



The syngas then passes through a series of heat exchangers called the Low Temperature Gas Cooling (LTGC) system that cools the syngas to near ambient temperature prior to entering the mercury removal section. The cooled syngas passes through a carbon bed that removes mercury as well as other trace pollutants.

After passing through the carbon bed the syngas is directed to the acid gas removal system. This system uses Selexol[®] solvent in a tray absorber to remove in excess of 99% of the H₂S from the syngas. The exact level of removal is dependent on the specific operating conditions and fuel characteristics. The syngas enters through a valve in the bottom of the H₂S absorber module and passes up through the absorber column. The Selexol[®] water solution is sprayed from the top of the column. The trays in the column increase the residence time of the gas and liquid interface allowing a high degree of H₂S transfer to the Selexol[®] solution. The H₂S rich Selexol[®] exits the bottom of the tower and is sent to a stripping column.

The clean syngas exiting the absorber passes through a knockout drum and demister to remove any entrained solvent. The syngas is then preheated by passing through the highest temperature LTGC exchanger. The syngas leaves the LTGC exchanger and is moisturized before being sent to the combustion turbines.

1.6 Power Generation

The cleaned syngas is then supplied to the power block where it fuels the two combustion turbines to produce an estimated nominal 464 MW. Heat Recovery Steam Generators are then used to produce steam from the turbine exhaust gases. This steam is combined with steam from the gasification and scrubbing processes, and expanded in a steam turbine to produce additional an additional 306 MW. The air separation unit and other operations at the facility are anticipated to consume approximately 140 MW, resulting in an estimated 630 MW net output of electricity to the bulk power grid.

1.7 Ancillary Equipment

The balance of the facility includes additional pieces of equipment that are necessary for start-up, maintaining and operating the facility.

1.7.1 Auxiliary Boiler

A natural gas fired boiler, rated at 278.8 MMBtu/hour and producing 200,000 lb/hr steam at 150 psig, is used to preheat the air separation unit and radiant section of the gasifiers and purging the gasifiers during start-up. This boiler is designed to only operate during start-up of the gasifiers. Operation of the boiler is limited to less than 500 hours per year.

1.7.2 Cooling Water System

A mechanical draft multi-cell cooling tower equipped with mist eliminators, distribution piping, and pumps will supply cooling capacity for the power block and air separation unit.

1.7.3 Wastewater Treatment

Wastewater from the gasification block is collected in a blow-down/reaction tank. Blowers are used to aerate the wastewater in reaction tanks where chemicals are added to adjust the pH and assist with the coagulation and flocculation in a clarifier. Precipitated and suspended solids are collected and removed from the clarifier in a sludge blow-down process. The sludge blow-down is further dewatered in a thickener. Overflow from the thickener is returned to the clarifier. Sludge blow-down from the thickener is routed through a filter press where it is dewatered and produces a suitable solid for

disposal in a landfill. Overflow from the clarifier is treated by additional chemical feed then routed to a 300,000 gallon demineralized water storage tank that is used to supply demineralized water to the gasification block.

Wastewater from the power block drains is routed through an oil-water separator. The water stream from the oil-water separator is discharged to the cooling tower. Blowdown from the cooling tower will be discharged to the Green River¹.

1.7.4 Fire Protection System

The facility design includes fire water supply from a raw water storage tank, fire protection pumps, and fire water piping to the air separation unit, gasification block (including the gas clean-up area) and power block.

1.7.5 Natural Gas Supply

The facility design also includes a natural gas backup supply to the power block boundary. This supply includes a pressure regulating and metering station. The natural gas will be supplied to the facility by pipeline.

1.8 Sulfur Recovery

There are three types of sulfur recovery units in use or permitted for IGCC plants. A permit has been issued recently for use of a CrystaSulf system. CrystaSulf uses a proprietary nonaqueous process where gaseous hydrogen sulfide (H_2S) is converted to solid crystals of pure elemental sulfur. Secondly, permits have been issued for systems that recycle the overhead of a one stage Claus unit back to an Acid Gas Removal unit. The applicant has proposed the most common type of unit, where the reduced sulfur off-gas is treated with thermal incineration prior to venting to the atmosphere. Thermal treatment produces a moderate amount of NO_x and SO_2 .

The H_2S rich Selexol[®] solution enters a tray tower stripping column. The Selexol[®] is treated to release the H_2S and then recycled for use in the absorber. The H_2S is sent to the sulfur recovery system where liquid sulfur is recovered in a Claus Process. The Claus process requires treating of the tail gas, which usually contains mostly H_2S and SO_2 but may contain traces of COS , CS_2 and elemental sulfur vapors. The tail gas is routed to a tail gas treatment (TGT) unit where the majority of the sulfur is recovered. The overhead of the TGT Unit is sent to a thermal oxidizer where the remaining H_2S and reduced sulfur are converted to SO_2 and any entrained solvent is destroyed before being emitted to the atmosphere.

2. EMISSIONS ANALYSIS

Pollutant emissions are produced by cleaning and combustion of syngas in the combustion turbines as well as produced by ancillary equipment including both point sources (Combustion Turbines, Thermal Oxidizer [for acid gas removal and sulfur recovery tail gas treatment], Cooling Tower, Flare, Coal Handling, Auxilliary Boiler and Emergency Fire Pump) and fugitive sources (Vehicular Traffic and Fuel Piles).

¹ A separate wastewater permit is required.

Pollutant emissions of the plant were based on

- 8760 hours per year of operating time unless stated differently
- 100% load capacity unless stated differently
- rated heat content for syngas is 251 Btu/scf and for natural gas is 1000 Btu/scf
- BACT limits established in section 4 of the application or emission factors noted in the calculations.

Table 2-1 Maximum Potential to Emit

Source Description	Emission Rates in tons/year						
	CO	VOC	NO _x	PM ₁₀ filterable	PM ₁₀ Total	SO ₂	H ₂ SO ₄
Combustion Turbines	919.9	28.1	628.6	161.2	411.6	299.2	66.44
Tail Gas Treatment-Thermal Oxidizer	41.5	2.8	71.9	2.8	2.8	91.2	
Flare	0.2	0.02	0.21	0.01	0.01	0.01	0.01
Cooling Towers				0.22			
Fuel Handling				0.14			
Coal Storage Pile				1.56			
Slag Storage Pile				1.20			
Oil-Water Sep							
Haul Roads				0.20			
Auxiliary Boiler	2.6	0.3	2.5	0.5	0.5	0.4	0.1
Fire Pumps	0.05	0.01	0.06	0.01	0.01	0.01	0.01
Total	964.22	31.2	703.3	167.8	414.9	390.8	66.5

The following tables summarize the emission limitations proposed by Cash Creek

Table 2-2 Emission Limitations Proposed by Applicant

EMISSION UNIT	DESCRIPTION	POLLUTANT	EMISSION LIMITATION BASED ON CT HEAT INPUT	EMISSION LIMITATION BASED ON GASIFIER HEAT INPUT
HRSG1 & HRSG2	Combustion Turbine 1 & 2 (each)	PM ₁₀ filterable (syngas & Natural gas)	0.0085 lb/mmBTU	0.0063 lb/mmBTU filterable (BACT)
		PM ₁₀ Total	0.0217 lb/mmBTU	0.0161 lb/mmBTU Total
		Opacity	20%	20 %
		CO – syngas	0.0485 lb/mmBTU	0.036 lb/mmBTU
		CO - natural gas	0.0449 lb/mmBTU	
		NO _x syngas	0.0331 lb/mmBTU	0.0246 lb/mmBTU
		NO _x natural gas	0.0246 lb/mmBTU	
		SO ₂ – syngas	0.0158 lb/mmBTU	0.0117 lb/mmBTU (BACT)
		SO ₂ - natural gas	0.001 lb/mmBTU	
		VOC – syngas	0.0015 lb/mmBTU	0.0011 lb/mmBTU
		VOC natural gas	0.0017 lb/mmBTU	
		H ₂ SO ₄ – syngas	0.0035 lb/mmBTU	0.0026 lb/mmBTU (BACT)
		H ₂ SO ₄ - natural gas	0.0001 lb/mmBTU	
		Hg – syngas		20 x 10 ⁻⁶ lbs/MWh
		Hg - natural gas		2.6 x 10 ⁻⁴ lbs/MMscf*

*AP-42 (7/98) (BACT not required)

Table 2-3 Emission Limitations Proposed by Applicant (continued)

EMISSION UNIT	DESCRIPTION	POLLUTANT	EMISSION LIMITATION
AUXB	Auxiliary Boiler, 278.8 MmBTU, 500 hours/year operating limit	PM/PM10	0.007 lb/MMBtu (BACT)
		Opacity	20% opacity
		SO ₂	0.006 lb/MMBtu (BACT)
		NO _x	0.036 lb/MMBtu (BACT)
		VOC	0.004 lb/MMBtu
FP	Emergency Fire Pump	PM/PM10	0.019 lb/MMBtu (BACT)
		CO	0.084 lb/MMBtu (BACT)
		SO ₂	0.0006 lb/MMBtu (BACT)
		NO _x	0.1 lb/MMBtu (BACT)
		VOC	0.0055 lb/MMBtu
Coal Handling System:			
THDC33	Transfer House #1 Baghouse	PM/PM10	20% opacity *
THDC34	Transfer House #2 Baghouse	PM/PM10	20% opacity *
CDRC35	Coal Reclaim Baghouse	PM/PM10	20% opacity *
Fugitive Emission Sources:			
CAREA 1	Dead Coal Storage Pile	PM/PM10	no visible emission crossing the property line
38F	Barge Unloading	PM/PM10	no visible emission crossing the property line
CAREA 2	Coal Stack	PM/PM10	no visible emission crossing the property line
CT1-10	Cooling Tower, Cell 1 through Cell 10	PM/PM10	0.0005% Drift Eliminators
	Slag Loadout	PM/PM10	No visible emissions crossing the property line
PAREA 1	Paved Haul Roads	PM/PM10	No visible emissions crossing the property line
AREA2	Slag Landfill	PM/PM10	No visible emissions crossing the property line

*Opacity is a surrogate for PM BACT

Table 2-4 Emission Limitations Proposed by Applicant (continued)

EMISSION UNIT	DESCRIPTION	POLLUTANT	EMISSION LIMITATION
FLARE1	Flare 3 pilot	PM ₁₀ filterable	0.000931 lb/hr
		PM ₁₀ Condensable	0.00279 lb/hr
		SO ₂	0.000294 lb/hr
		NO _x	0.049 lb/hr
		CO	0.0412 lb/hr
		VOC	0.0027 lb/hr
TO 30	Thermal Oxider	PM/PM10	0.63 lb/hr
		SO ₂	20.82 lb/hr
		NO _x	16.41 lb/hr
		CO	9.46 lb/hr
		VOC	0.63 lb/hr

2.1 Initial Compliance Demonstration

Proposed sources are required to demonstrate compliance by performance testing within 60 days after achieving the maximum production rate at which the affected facilities will be operated but not later than 180 days after initial start-up of such facilities. The combustion turbines and auxiliary boiler shall be required to be performance tested for pollutants by applicable reference methods, or by equivalent or alternative test methods specified in this permit or approved by the cabinet or U.S. EPA as follows:

Emission Units 01, and 02 shall be performance tested initially for compliance with the emission standards for PM/PM₁₀ (filterable and condensable); sulfur dioxide (SO₂); nitrogen oxides (NO_x); and carbon monoxide (CO), VOCs, mercury; and H₂SO₄, and fluorides.

Emission Unit 03 shall be performance tested initially for compliance with the emission standards for PM/PM₁₀ (filterable); nitrogen oxides (NO_x); and carbon monoxide (CO),

<u>Pollutant</u>	<u>Reference Method</u>
Particulate matter	Method 201 and Method 202
Opacity	Method 9
Sulfur dioxide	Method 6
Nitrogen oxides	Method 7
Carbon monoxide	Method 10
VOC	Method 25A and 18 if needed

3. APPLICABLE AND NONAPPLICABLE REGULATIONS

This section presents a discussion on the air quality regulations.

Applicable Regulations

3.1 Prevention of Significant Deterioration (PSD)

401 KAR 51:017 , Prevention of Significant Deterioration (PSD) of air quality, applies to the construction of a new major stationary source that commences construction after September 22, 1982, and locates in an area designated attainment or unclassifiable under 42. U.S.C. 7407(d)(1)(A)(ii) and (iii). Cash Creek is a "Major stationary source" as defined in 401 KAR 51:001, Section 1(120)(b) for the PSD program because it is a fossil fuel-fired steam electric plant of more than 250 MMBtu per hour heat input and will emit, or has the potential to emit, 100 tons per year or more of a regulated NSR pollutant. Pursuant to 40 CFR 81.318 the facility will be located in a location that is "Better than national standards" or "Unclassifiable/Attainment" for all pollutants.

Therefore, Cash Creek is subject to PSD requirements. A PSD review involves the following six requirements:

1. Demonstration of the application of Best Available Control Technology (BACT).
2. Demonstration of compliance with each applicable emission limitation under Title 401 KAR Chapters 50 to 65 and each applicable emissions standard and standard of performance under 40 CFR 60, 61, and 63.
3. Air quality impact analysis.
4. Class I area impact analysis.

5. Projected growth analysis.
6. Analysis of the effects on soils, vegetation and visibility.

3.2 **New Source Performance Standards (NSPS)**

The Clean Air Act of 1970 directed U.S. EPA to establish New Source Performance Standards, or NSPS, for specific industrial categories. There are three NSPS applicable requirements to the Cash Creek project. In some cases the emission limit or technology standard based on these and other applicable regulations may be superseded by the BACT requirements which are more stringent under PSD (see Section 5, Best Available Control Technology Review). However, any specific testing, monitoring, record keeping, and reporting requirements contained in these regulations will still have to be met by the source in addition to any requirements under PSD.

40 CFR 60 Subpart Da - Standards of Performance for Electric Utility Steam Generating Units (incorporated by reference in 401 KAR 60:005 Section 3(c))

40 CFR Part 60, Subpart Da requires all new, modified, or reconstructed steam generating units with a maximum heat input capacity greater than 250 MMBtu/hour for which construction is commenced after September 18, 1978 (44 FR 33613, June 11, 1979) to meet limitations on emissions of PM, SO₂, and NO_x.

Table 3-1 Subpart Da Emission Limits

POLLUTANT	EMISSION LIMIT	AVERAGING BASIS
Opacity	20% except for one 6-minute period per hour	6-minutes
PM	0.14 lb/MWh or 0.015 lb/MMBtu or (0.03 lb/MMBtu and 99.9% reduction)	3-hour
SO ₂	0.8 lb/ MMBtu, 90% reduction or 0.20 lb/MMBtu, 0% reduction	30-day rolling
NO _x	0.50 lb/ MMBtu, 25% reduction	30-day rolling
Hg	20 x 10 ⁻⁶ lb/MWh or 0.020 lb/GWh	12-month rolling

On February 27, 2006, U.S. EPA revised 40 CFR Part 60, Subpart Da to reduce allowable emissions of NO_x, SO₂ and PM; and added a new Hg emission limits; for all new, modified, or reconstructed steam generating units with a maximum heat input capacity greater than 250 MMBtu/hour for which construction is commenced after February 28, 2005. (70 FR 9706, February 28, 2005). The final version clarifies that heat recovery steam generators that are associated with stationary combustion turbines burning fuels containing 75 percent or more synthetic-coal gas are subject to Subpart Da and are not subject to 40 CFR Part 60, Subpart KKKK. Therefore, Subpart Da applies to Cash Creek. Any emission limits derived from the BACT analysis will be reconciled with Subpart Da emission limits.

40 CFR 60 Subpart GG - Standards of Performance for Stationary Gas Turbines (incorporated by reference in 401 KAR 60:005 Section 3(l))

The requirements of 40 CFR Part 60 Subpart GG ("Subpart GG") apply to all stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the lower heating value of the fuel fired. Subpart GG includes an SO₂ emission limit of 0.015 percent SO₂ by volume @ 15% O₂ on a dry basis (150 ppmvd @15% O₂) and a NO_x requirement that is applicable to units with heat inputs greater than 100 MMBtu/hr. The NO_x requirement is in the form of an emission limit equal to 75 ppmvd @ 15% O₂ based on the following formula:

$$E = 0.0075 \times \left(\frac{14.4}{Y} \right) + F$$

E = allowable NO_x percent emissions at 15% O₂ on a dry basis

Y = heat rate at max load (kJ/Whr) but less than 14.4kJ/Whr

F = NO_x emission allowance for fuel bound nitrogen

Since the total heat input to the combustion turbines at Cash Creek is greater than 100 MMBtu/hr both the SO₂ and the NO_x requirements of subpart GG apply to Cash Creek. However, Cash Creek must comply with significantly more stringent BACT emission limits for SO₂ and NO_x which also demonstrate compliance with Subpart GG.

40 CFR 60, Subpart JJJJ, National Emission Standards for Stationary Spark Ignition Internal Combustion Engines and National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (Spark Ignition Internal Combustion Engines (SI ICE));

The applicant did not include this in the application. However, the Division has determined that it is applicable to the Emergency Fire Pump. On June 12, 2006, U.S. EPA proposed in the Federal Register (71 FR 33804, June 12, 2006) revised NO_x, CO and NMHC emission limits under 40 CFR Part 60, Subpart JJJJ, for all new, modified, or reconstructed stationary Spark Ignition Internal Combustion Engines. This addresses emissions from new, modified and reconstructed stationary Spark Ignition Internal Combustion Engines (SI ICE). These stationary engines are required to comply with the emission standards for nitrogen oxides (NO_x), carbon monoxide (CO) and non-methane hydrocarbons (NMHC). The Division has determined that the limits set by the proposed regulation are BACT for this emissions unit.

40 CFR Part 60, Subpart Y, Standards of Performance for Coal Preparation Plants, (incorporated by reference in 401 KAR 60:005 Section 3(ff))

40 CFR Part 60, Subpart Y, Standards of Performance for Coal Preparation Plants, incorporated by reference in 401 KAR 60:005, requires certain coal processing facilities to comply with certain particulate standards. Activities regulated by this NSPS include crushing, screening, conveying, and transferring of coal. Emission points are subject to an opacity limitation of 20 percent. . For point sources of these regulated activities enclosures, baghouses, vent filters and fogging that provide removal efficiencies in excess of 99% are selected as BACT.

40 CFR Part 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, (incorporated by reference in 401 KAR 60:005 Section 3(1)(d))

40 CFR Part 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, incorporated by reference in 401 KAR 60:005, apply to all steam generating units that commence construction, modification or reconstruction after June 19, 1984, and that have a heat input capacity greater than 29 MW (100 MMBtu/hr). This NSPS requires that SO₂ and NO_x emissions not exceed 0.20 lb/ MMBtu on a 30 day rolling average and emissions of particulate matter not be in excess of 0.030 lb/MMBtu. Proper boiler design, operation and maintenance, low NO_x burners using natural gas as fuel, with an operational limit of less than 500 hours provide BACT for the Auxillary Boiler.

3.3 Maximum Achievable Control Technology Standards (MACT)

40 CFR Part 63, Subpart B, Requirements for Control Technology Determinations for Major Sources in Accordance with Clean Air Act

HAP emissions from Cash Creek will be less than 25 tons per year of combined HAP's and 10 tons per year for any single HAP. Therefore, Cash Creek is not a major source of HAPs

40 CFR Part 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

On April 7, 2004, EPA proposed staying the effectiveness for two types of stationary combustion turbines, lean premix gas-fired turbines and diffusion flame gas-fired turbines, pending the outcome of EPA's proposal to delete these subcategories from the source category list (68 FR 18338, April 7, 2004). Cash Creek's turbines are diffusion flame gas-fired turbines. Under this stay, new sources in the two categories are temporarily relieved of the obligation to apply pollution controls and to comply with associated operating, monitoring, and reporting requirements. However, such sources must continue to submit Initial Notifications pursuant to 40 CFR 63.6145. If the subcategories are not ultimately delisted, the stay will be lifted, and all sources in the subcategories constructed or reconstructed after January 14, 2003 will then be subject to the final standards.

40 CFR Part 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants, Industrial, Commercial, and Institutional Boilers and Process Heaters.

As Cash Creek is not a major source of HAP emissions, this regulation is not applicable.

3.4 Compliance Assurance Monitoring (CAM)

40 CFR Part 64

The U. S. EPA promulgated CAM regulations on October 22, 1997 as 40 CFR Part 64. The regulations require that new major sources (defined in CAM regulations as those whose potential criteria pollutant emissions prior to a control device exceed 100 tons/yr) must have a monitoring plan for each such pollutant. The proposed Cash Creek facility will have pre controlled emissions of NO_x in excess of 100 tons per year; therefore, CAM does apply to Cash Creek. Since Kentucky has a combined permitting program, the Title V operating permit must be issued with the Prevention of Significant Deterioration (PSD) construction permit. In accordance with 40 CFR 64.5, Compliance Assurance Monitoring requirements have been included in the permit for NO_x emissions from the combustion turbines. The use of the NO_x continuous emissions monitors will ensure compliance with NO_x CAM requirements.

3.5 Phase II Acid Rain Permits

Cash Creek applied for an Acid Rain permit with this PSD application (see Appendix B) to meet the Phase II Acid Rain requirements. Additionally, Acid Rain regulations, 40 CFR 72 through 40 CFR 78 apply. Part 75 requires continuous emission monitoring for NO_x and SO₂

3.6 Title V Operating Permit

As Cash Creek will emit greater than 100 tons per year of several pollutants it is subject to Title V permitting requirements of 401 KAR 52:020. As Kentucky's program is a combined permitting program, PSD construction requirements and Title V operating requirements are included in the initial permit.

3.7 State Regulations

Applicable State air quality regulations are summarized as follows.

401 KAR 51:160, NO_x Trading Program

401 KAR 51:160 requires affected units to acquire NO_x emission allowances equal to their NO_x emissions during the ozone season. Cash Creek will acquire allowances necessary to meet compliance requirements of all applicable state and federal NO_x trading programs.

401 KAR 59:016. New electric utility steam generating units(State-only).

For an electric utility combined cycle gas turbine, the affected facility is that part of the system that is the steam generating unit and the standards parallel the Federal NSPS standards. Cash Creek will be in compliance with Kentucky standards when it is in compliance with Federal NSPS standards. The emission and operating limits proposed as BACT are more stringent than Kentucky or Federal standards.

401 KAR 63:015, Flares

Emissions into open air of PM from any flare shall be no greater than 20% opacity for more than three (3) minutes in any one (1) day. Compliance will be accomplished by performing a qualitative visual observation of the opacity of emissions from the flare on a weekly basis and during the occurrence of any syngas flaring and maintain a log of the observations. If visible emissions determined by Reference Method 9 from the flare exceed the standard initiate an inspection of the flare and the entire process and make any necessary repairs.

401 KAR 63:010, Fugitive Emissions

Requirements apply to fugitive dust emissions from roads, material handling and storage operations. The regulation requires the owner or operator to utilize reasonable precautions to prevent particulate matter from becoming airborne and prohibits visible fugitive dust at the property line.

401 KAR 63:020, Potentially Hazardous Matter or Toxic Substances

The regulation applies to certain facilities that emit potentially hazardous matter or toxic substances that are not elsewhere subject to State regulations. Cash Creek has potential emissions that require additional impact analysis as part of PSD analysis and this analysis was expanded to address this regulation. The analysis results are in Section 8 of the application.

401 KAR 50:042, Good Engineering Practice Stack Height

Table 3 - Cash Creek Stack Heights vs. GEP Stack Heights

The regulation applies such that a source may use it in establishing its applicable State Implementation Plan (SIP) emission limitation. A dispersion model accounting for aerodynamic plume downwash was used in the air quality impact assessment to determine GEP for Cash Creek stacks. The building structures were input directly into the AEROMOD model and the Building Profile Input Program (BPIP) routine calculated the downwash parameters. Table 3-5 of the application lists the modeled stack heights and results of the BPIP model showing the corresponding GEP stack heights. The complete BPIP model inputs and outputs are contained in Appendix K of the application.

Stack ID	Stack Description	Actual Stack Height (meters)	GEP Stack Height (meters)
AUXB	Auxiliary Boiler	18.29	65
HRSG1	HRSG 1 Stack	60.66	65
HRSG2	HRSG 2 Stack	60.66	65
TO30	Thermal Oxidizer	59.44	65
THDC33	Transfer House #1 Dust Collector	6.1	76.2
THDC34	Transfer House #2 Dust Collector	6.1	76.2
CRDC35	Coal Reclaim Dust Collector	6.1	76.2
FLARE	Flare	61.81	65
CT1-CT10	Cooling Tower Cells 1-10	15.24	65
FP	Fire Pump	12.19	65
K3	Barge Unload Belt to Hopper	6.1	76.2

3.8 Non-Applicable Regulations

40 CFR Part 60, Subpart J Standards of Performance for Petroleum Refineries (incorporated by reference in 401 KAR 60:005 Section 3(1)(n))

While 40 CFR Part 60, Subpart J contains standards for Claus Plants, it is limited to only those Claus units that are located or co-located with Petroleum Refineries and not IGCC units. The BACT analysis and permit terms were written with the view of this standard's monitoring and recordkeeping techniques.

401 KAR 60:020 (Proposed, not yet applicable) Mercury Budget Trading Program. Promulgated to meet the requirements of 40 CFR 60 Subpart HHHH Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units

The Commonwealth is currently in the process of adopting a regulation that will fulfill the requirements of 40 CFR 60 Subpart HHHH. Cash Creek is expected to be required to obtain mercury emission credits for either existing sources or purchase them from the Commonwealth's new source "pool".

4. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) REVIEW

Pursuant to 401 KAR 51:017, a major stationary source subject to a PSD review shall meet the following requirements:

- (a) The proposed source shall apply the best available control technology (BACT) for each pollutant that it will have the potential to emit in significant amounts.
- (b) The proposed source shall meet each applicable emissions limitation under Title 401 KAR 50 to 65, and each applicable emission standard and standard of performance under 40 CFR 60, 61, and 63.

Table 4-1 Emissions Increase vs. Significant Levels

The following pollutants are subject to BACT: particulate matter (PM), (PM₁₀ and PM_{2.5}), sulfur dioxide (SO₂), nitrogen oxides (NO_x), carbon monoxide (CO), and sulfuric acid mist (H₂SO₄). However a BACT review is not required for VOC because the predicted emissions are below 40 tons per year.

POLLUTANT	POTENTIAL EMISSIONS INCREASE FROM THE PROPOSED FACILITY (TONS/YEAR)	SIGNIFICANT NET EMISSIONS LEVEL (TONS/YEAR)
Total Particulate	415	25
PM ₁₀	168	15
SO ₂	391	40
H ₂ SO ₄	67	7
NO _x	704	40
CO	965	100
VOC	32	40
Pb	.02	0.6

4.1 BACT Overview

Cash Creek submitted a top-down Best Available Control Technology (BACT) analysis following the U.S. EPA guidance, "New Source Review Workshop Manual" (U.S. EPA, October 1990). The key steps involved with the top-down BACT process are as follows:

1. Identify all control technologies
2. Eliminate technically infeasible options
3. Rank remaining control technologies by control effectiveness
4. Evaluate most effective controls considering economic, environmental, and energy impacts, and document results
5. Select BACT.

4.2 Step 1 - Identify All Control Technologies

Using the top-down approach, Cash Creek selected various technologies for analysis of technical and practical feasibility, and then applied economic cost-effectiveness analyses where the top ranked technology was not selected.

4.2.1 Generating Technology Analysis and Selection

Cash Creek considered three electricity generating technologies in their design evaluation which included: Pulverized Coal (PC), Circulating Fluidized Bed (CFB) combustion and Integrated Gasification Combined Cycle (IGCC).

PCs and CFBs emission reductions are accomplished with post-combustion emission control technologies (such as SCR, SNCR, FGD and FF), whereas, IGCC emissions are controlled before or during combustion. In an IGCC plant, particulate matter, mercury, SO₂, and H₂SO₄, emissions are controlled by cleaning the syngas. CO and VOC emissions are minimized by proper process design and use of combustion controls. For an IGCC plant, the particulate removal process will reduce emissions by more than 99.9% and acid gas/sulfur recovery systems will reduce potential SO₂ emissions by more than 99%. NO_x is minimized through nitrogen injection prior to combustion of syngas in the combustion turbines, and by Selective Catalytic Reduction post combustion. A comparison is shown below of typical permitted limits.

Table 4-2 Comparison of PC, CFB, and IGCC Emission Rates

Pollutant	PC lb/MMBtu	CFB lb/MMBtu	IGCC lb/MMBtu
PM ₁₀ *	0.015	0.012	0.009
SO ₂	0.187	0.150	0.033
NO _x	0.050	0.070	0.059
CO	0.150	0.150	0.040
VOC	0.005	0.004	0.003
H ₂ SO ₄	0.005	0.005	0.004

*based on filterable particulate emissions

The proposed emission rates are listed in Table 4-6 of the application and below.

Table 4-3 Proposed Emission Rates

Pollutant	Emission Rate Gasifier Heat Input (lbs/MMBtu)	Emission Rate C T Heat Input (lbs/MMBtu)	Control Technology
NO _x	0.0246	0.0331	Nitrogen injection and SCR
SO ₂	0.0117	0.0158	AGR syngas cleanup
PM ₁₀ -Filterable	0.0063	0.0085	syngas cleanup
PM ₁₀ -Total	0.0161	0.0217	
CO	0.036	0.0485	combustion controls
VOC	0.0017	0.0015	combustion controls
H ₂ SO ₄	0.0026	0.0035	AGR syngas cleanup

4.2.2 Fuel selection

Cash Creek's CTs are designed to use syngas derived from bituminous coal with natural gas as the secondary and start-up fuel.

Cash Creek considered and dismissed coal washing as an ancillary emission control measure due to detrimental impacts on the gasification process. Cash Creek indicated that:

- Reduction of ash entering the gasification process could require the addition of fluxant material (such as sand) to facilitate the gasification and slag removal process.
- An attempt to over-scrub lower sulfur content fuels in the AGR would produce detrimental results. Over scrubbing results in additional CO₂ capture, which acts as a diluent in the Sulfur Recovery Unit and stresses the Tail Gas Treatment Unit, resulting in increased emissions of SO₂ from the thermal oxidizer.
- The particulate washing process associated with the IGCC system achieves the same average removal efficiency regardless of ash content.

The Division concurs that coal washing should not be required.

4.2.3 Control Technology Options

To determine available technologies Cash Creek considered several sources including: EPA's RACT/BACT/LAER Clearinghouse and Control Technology Center (RBLC); recent submitted PSD applications; recently issued or proposed permits; and information from control technology vendors and engineering/environmental consultants. These control technologies are identified for each applicable pollutant are listed below.

Table 4-4 Possible Control Strategies & Technologies

POLLUTANT	COMBUSTION CONTROL TECHNOLOGIES	MATERIAL HANDLING CONTROL TECHNOLOGIES	COOLING TOWERS	FUGITIVE
PM/PM ₁₀	<u>Pre-Combustion</u> IGCC Syngas Scrubbing <u>Post-Combustion</u> Baghouse Electrostatic Precipitator ("ESP") Wet ESP ("WESP") Scrubbers Cyclone	Enclosures Baghouse Fogging	Drift Eliminators	Suppressants Compaction Telescopic Chutes
SO ₂ H ₂ SO ₄	<u>Pre-Combustion</u> IGCC Acid Gas Removal Coal Washing <u>Post-Combustion</u> Wet Flue Gas Desulfurization(WFGD) Dry Sorbent Injection ("DSI") Dry Scrubbers	N/A	N/A	N/A
NO _x	<u>Pre-Combustion</u> Diluent Injection Dry Low NO _x Burners <u>Post-Combustion</u> Selective Catalytic Reduction ("SCR") Selective Non-Catalytic Reduction ("SNCR")	N/A	N/A	N/A
CO	<u>Pre-Combustion</u> Excess Air Proper Design and Operation <u>Post-Combustion</u> Thermal Oxidation Catalytic Incineration	N/A	N/A	N/A

4.3 Step 2 - Technical Feasibility Analysis

The control technologies for PM/PM₁₀, SO₂, NO_x, CO, VOC and H₂SO₄ were then evaluated for technical feasibility and applicability. Cash Creek determined that Thermal Oxidation (TO) [except for its use in the Acid Gas Removal process], Catalytic Incineration (CI), dry Low NO_x Burners (LNB), and SCONOX to be infeasible because they are not available and/or not applicable. Cash Creek's other findings are as follows:

Thermal Oxidation (TO) - As a control device for CO, Thermal Oxidation is not listed in the RBLC database for any proposed or permitted electric generating process, including IGCC. Therefore, Cash Creek determined that Thermal Oxidation is not available or applicable.

Catalytic Incineration (CI) - As a control device for CO, catalytic incineration is not

listed in the RBLC database, EPA literature for utility boiler air emissions control, or any proposed or permitted electric generating process, including IGCC. Therefore, Cash Creek determined that Thermal Oxidation is not available or applicable.

Low NO_x Burners (LNB) - One method to reduce thermal NO_x is to use LNB. However, Cash Creek rejected this option since hydrogen is a major constituent of synthesis gas and hydrogen's high flammability and flame speed can initiate flashback and combustor failure. Also, there are no commercially available LNBs for IGCCs firing syngas. Therefore, Cash Creek determined that LNBs are not available or applicable for IGCC units firing syngas. Since LNB's were rejected as being unfeasible due to usage of syngas and not natural gas, the permit has been conditions to limits the amount and duration of natural gas combustion.

4.4 Step 3 - Ranking of the Remaining Control Technologies

After eliminating the technically infeasible control alternatives, Cash Creek reviewed and ranked each control technology for effectiveness.

First, Cash Creek identified the following control technologies as having the most stringent emission limits for non-IGCC coal-fired units:

Table 4-5 Summary of Control Technologies

POLLUTANT	SOURCE	MOST STRINGENT EMISSION LIMIT	CONTROL TECHNOLOGY
PM/PM ₁₀ PM _{2.5}	Boilers	0.012 lb/MMBtu (filterable) 0.018 lb/MMBtu (total)	Baghouse or Electrostatic Precipitator
	Materials Processing	99+% control	Baghouse Enclosures
	Cooling Towers	99.9995% control	Mist (Drift) Eliminators
	Fugitives	20% Opacity	Suppressants, Compaction Telescopic Chutes
SO ₂	Boilers	0.08 lb/MMBtu	WFGD/Western US coal
NO _x	Boilers	0.05 lb/MMBtu	Boiler Design and Operation/ Low NO _x Burners/ SCR
CO	Boilers	0.085 lb/MMBtu	Boiler Design & Operation
H ₂ SO ₄	Boilers	0.004 lb/MMBtu	WESP and WFGD

As IGCC is a new technology for electric generation, Cash Creek was only able to identify 8 sources available for comparison. The most stringent emission limits for existing and proposed IGCC units are listed below:

Table 4-6 Summary of Most Stringent Limits for Existing and Proposed IGCC Sources

Pollutant	Source	Most Stringent Emission Limit
PM/PM ₁₀	Wabash SICEC	0.005 lb/MMBtu (filterable) not met 0.009 lb/MMBtu
SO ₂	Lima	0.02 lb/MMBtu
NO _x	SICEC	0.059 lb/MMBtu
CO	Elm Road	0.03 lb/MMBtu
VOCs	Elm Road	0.002 lb/MMBtu

H ₂ SO ₄	Elm Road	0.00005 lb/MMBtu
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Using the emission information of the two previous tables, control technologies were ranked in order of decreasing effectiveness, as follows:

Table 4-7 Ranking of Control Technologies by Effectiveness

Pollutant	Control Technology	Potential Add-On Control Efficiency (%)*
PM/PM ₁₀ Combustion Turbine	IGCC Syngas Scrubbing	99+
	Baghouse or ESP/WESP	99+
	Scrubber	99+
	Cyclone	90+
PM/PM ₁₀ Material Handling	Baghouse	99+
	Enclosures with Vent Filters	99+
	Fogging	99+
PM/PM ₁₀ Cooling Towers	0.0005% Drift Eliminators	90+
PM/PM ₁₀ Fugitives	Suppressants	80-90
	Compaction	80-90
	Telescopic Chutes	80-90
SO ₂	IGCC AGR	99+
	WFGD	98+
	Dry Scrubber	80-90
	Coal Washing	30-35
NO _x	SCR	60-90
	Diluent Injection	40-75
	SNCR	40-70
	Proper Design and Operation	Varies
CO	Proper Design and Operation	Varies
H ₂ SO ₄	IGCC AGR	99+
	DSI/Baghouse/WFGD	99+
	WESP	98+
VOCs	Proper Design and Operation	Varies

Cash Creek noted that, in some instances, reaching those limits for one pollutant may prohibit attaining the most stringent limit for another. For example combustion processes reducing NO_x to the lowest level may significantly increase CO or H₂SO₄ emissions.

4.5 Step 4 - Top Down Evaluation of Control Options

4.5.1 Particulate Matter

There are four sources of particulate matter from Cash Creek: combustion turbines, material handling units, cooling tower and fugitive sources.

4.5.1.1 Particulate Matter (PM₁₀ and PM_{2.5}) (IGCC)

Although PM_{2.5} is a regulated NSR pollutant and there is a National Ambient Air Quality Standard (NAAQS) for PM_{2.5}, which became effective on September 16, 1997; as discussed in the Memorandum from John S. Seitz, Director Office of Air Quality Planning and Standards, to Regional Air Directors, Interim Implementation of New Source Review for PM_{2.5} (Oct. 23, 1997); until U.S. EPA promulgates the PM_{2.5} major NSR regulations, States and local air pollution control agencies should use PM₁₀ as a surrogate for PM_{2.5}. On March 29, 2007, EPA issued the Clean Air Fine Particle Implementation Rule, which has begun to define requirements for State Implementation Plans to address improving PM_{2.5} nonattainment areas. However, this rule specifically does not address requirements for NSR requirements for PM_{2.5}. These requirements will

be addressed in separate rulemaking. Therefore, at this time the BACT analysis for PM_{10} shall be a surrogate for $PM_{2.5}$.

In a typical combustion process, particulate matter is removed by post-combustion processes such as fabric filters or electrostatic precipitators. However, in an IGCC plant, particulate matter could damage the turbine(s), so it is necessary to use pre-combustion controls. Therefore, particulate removal is an integral part of the gasification process. Heavier mineral and ash matter, referred to as coarse slag, is not entrained in the syngas and is captured in the gasifier. As noted in Section 1.4, prior to leaving the gasifier, syngas passes over a water pool located at the bottom of the unit which enhances collection of the slag.

Fine slag is composed of mineral compounds and fuel particles that are not completely gasified (unburned carbon). This material is carried from the gasifier and is removed by scrubbing with water to remove entrained particulates.

These processes are approximately 99.9% efficient at removing particulate matter, and results in an emission limit for PM/PM_{10} (filterable) of 0.0063 lb/MMBtu based on a 3 hour average while firing syngas or natural gas. This limit is more stringent the PM_{10} limit achieved at current operating IGCC units.

Cash Creek noted that sulfuric acid mist is the most widely recognized form of condensable PM emitted by combustion sources. Other inorganic species that can contribute to condensable PM emissions include ammonium bisulfate, other acid gases such as HCL, HF and trace volatile metals. Because sulfuric acid mist is the main constituent of inorganic condensable PM, and because control technologies that remove sulfuric acid mist are also effective in removing other acid gases, Cash Creek indicated that the control of sulfuric acid mist serves as an effective proxy for the control of condensable PM. Furthermore, control devices applicable to SO_2 emissions reductions in an IGCC are the same that are applicable to control H_2SO_4 . Therefore, Cash Creek concluded that a single analysis is required to determine BACT for SO_2 , H_2SO_4 , and condensable PM.

4.5.1.2 Particulate Matter (Material Handling)

Cash Creek has selected baghouses, vent filters and fogging as BACT for PM/PM_{10} emission controls for material handling facilities for coal and slag. Use of these emission controls is expected to result in a removal efficiency of approximately 99.5%, and therefore represents BACT. Fogging will be used in instances where it provides controls equal to or better than baghouse or filter. The Division concurs that these measures are BACT.

4.5.1.3 Particulate Matter (Cooling Towers)

The highest control efficiency to reduce the amount of drift (PM_{10} emissions) from cooling towers involves the instillation of drift eliminators. These are designed to remove as many droplets of particulate as feasible before leaving the cooling towers, thus minimizing PM emissions and conserving water usage by the cooling towers. Cash Creek has selected 0.0005% drift eliminators as BACT for particulate control on the cooling towers.

4.5.1.4 Particulate Matter (Fugitives)

Fugitive emissions originate at active and inactive areas of storage piles, roads, and loading and unloading operations. Cash Creek proposes to use suppressants (both water and chemical); compaction; and telescopic chutes, stacking tubes, and reduced drop heights to reduce fugitive emissions. Inactive long-term storage piles will be compacted and suppressed as needed. When storage piles are active or if erosion causes emissions, suppressants will be used to control fugitive emissions. Drop heights will be optimized to reduce emissions while allowing for proper operation. Chutes or stacker tubes will be used when loading coal to the storage pile. Permanent roads and parking lots will be paved. These technologies represent the highest control levels for fugitive particulate emissions from the facility.

4.5.2 Sulfur Dioxide and Sulfuric Acid Mist (IGCC)

Both SO₂ and H₂SO₄ emissions from an IGCC combustion turbine are produced in relationship to the concentrations of sulfur constituents in the syngas. Possible control devices for reducing SO₂ and H₂SO₄ emissions include both post-combustion and pre-combustion devices. Post-combustion Wet Flue Gas Desulfurization (WFGD) alone or combined with other controls (such as Wet Electrostatic Precipitators) has been the preferred method for SO₂ and inorganic condensable emissions (H₂SO₄) reduction and BACT compliance for high sulfur fossil-fueled combustion sources. However, in an IGCC, the syngas is treated prior to combustion, which is necessary to avoid damage to the turbine from acid gas and particulates and generally results in greater removal efficiencies. The table below summarizes the data used by Cash Creek in its BACT analysis.

Table 4-8 SO₂ and H₂SO₄ Emission Control Options

Pollutants	Control Technology	Potential Control (%)
SO ₂	<u>Pre-Combustion</u>	
	Physical Absorption	99.5+
	Chemical Absorption	99.4+
	Coal Washing	30-35
	<u>Post Combustion</u>	
	WFGD	98+
	Dry Scrubber	80-90

Since the highest available removal efficiencies are associated with pre-combustion controls, Cash Creek did not consider post-combustion controls in its BACT analysis.

Cash Creek noted that the gasification process involves conversion of a coal slurry and oxygen at very high temperature and pressure into a CO and H₂ rich fuel. Byproducts that result from using high sulfur coal as a feedstock are the gaseous pollutants H₂S and COS. These pollutants are removed in a pre-combustion Acid Gas Removal System ("AGR"), which is very effective in removing the H₂S but does not readily remove COS. To address this removal problem the COS is mixed with water in a hydrolysis reactor which produces H₂S and CO₂. The syngas is then cooled and sent to the AGR for cleaning. The AGR is essentially a scrubbing operation that can be performed by chemical or physical absorption. There are currently two physical absorption solvents, *Selexol*[™] and *Rectisol*[™], and one chemical absorption solvent, MDEA, available for use at Cash Creek.

Physical Absorption

Physical absorption methods, including Selexol™ and Rectisol™, use solvents that dissolve acid gases under pressure. Solubility of an acid gas is proportional to its partial pressure and is independent of the concentrations of other dissolved gases in the solvent. Thus, increased operating pressure in an absorption column facilitates separation and removal of an acid gas like H₂S. The dissolved acid gas can then be removed from the solvent, which is regenerated, by depressurization in a stripper.

Union Carbide's Selexol™ solvent made of dimethyl ether or polyethylene glycol has been used successfully in chemical facilities to treat process gas streams. Feed gas is cooled with water and then flows to an absorption tower where it is introduced to the Selexol™ solvent in a countercurrent flow. Acid gases in the feed gas are absorbed into the solvent, and a clean feed gas is withdrawn from the top of the absorber column. Acid gas rich solvent from the absorber is regenerated by flashing it to medium pressure, then reheating the gas to the solvent boiling point and stripping the solvent. Based on GE information, and engineering judgment, the Selexol™ process removes 99.8% of the sulfur contained in the syngas.

Rectisol™, also a physical absorption process, uses cold methanol as the physical solvent. Sour syngas entering the AGR is cooled, and trace chemical components are removed with a cold methanol pre-wash. Then, H₂S is physically absorbed from the raw gas using CO₂-rich methanol. Raw gas is removed from the top of the absorption column, with clean syngas removed from a lower point in the column. The solvent is reclaimed through pressure reduction, stripping, and re-boiling. Although Rectisol™ has not been used in an AGR serving an IGCC facility, there are no known technical limitations that would render the process technically infeasible for the AGR system. Based on information from GE, and engineering judgment, the Rectisol™ process removes 99.9% of the sulfur contained in the syngas.

Chemical Absorption

In a chemical absorption process, acid gases in the sour syngas are removed by chemical reactions with a solvent that is subsequently separated from the gas and regenerated. The amine solvent considered for chemical absorption is methyldiethanolamine ("MDEA"). Amine solvents, such as MDEA, react forming a chemical bond between the acid gas and the solvent in an absorption tower. Solvent is reclaimed by a heating process in a stripper tower producing regenerated MDEA and a concentrated H₂S stream that is directed to the sulfur recovery process. The sulfur recovery process removes the sulfur and treats the tail gas by thermal oxidation.

Chemical absorption, successfully used at existing IGCC facilities to reduce the sulfur content of syngas, is a feasible technical option to serve Cash Creek. Based on information from GE, and engineering judgment, Cash Creek concluded that the MDEA process could remove 99.4% of the sulfur contained in the syngas.

BACT Selection for SO₂

The most effective SO₂ control systems that are technically feasible for the proposed facility are physical absorption AGR systems, using Selexol™ or

Rectisol™ solvents. Both are capable of removing over 99% of the sulfur from the syngas based on feasibility studies performed by vendors with Selexol achieving 0.0117 lb/MMBtu removal and Rectisol possibly reaching 0.00585 lb/MMBtu removal. Cash Creek has selected the Selexol™ system to reduce SO₂ and acid gases emissions. Since Rectisol™ has the potential to more effectively reduce SO₂ emissions and acid gases, Cash Creek felt that a BACT analysis requires an evaluation of the economic, energy and environmental impacts associated with the both the Selexol™ system and the Rectisol™ systems. However, Cash Creek noted that no IGCC facilities operate with either a Selexol™ or Rectisol™ AGR system; so accurate costs associated with these technologies are based on vendor discussions, trade show presentations, similarly proposed sources, or discussions with non-utility gasification sources.

Economic Evaluation

In its economic evaluation, Cash Creek analyzed both average and incremental cost effectiveness.

Because of the potential for damage to the turbine, Cash Creek did not feel it was realistic to use a completely uncontrolled number as a baseline to use in calculating "average cost effectiveness", which is typically expressed as annual costs of removal divided by tons of pollutant removed. Instead, Cash Creek used what it felt was a more realistic baseline by using emissions from the Wabash River IGCC unit and a theoretical analysis using MDEA to control SO₂. Wabash River represents actual operating experience while MDEA represents the minimum control feasible. The following tables are the numbers used in Cash Creek's analysis.

Table 4-9 Average Cost Effectiveness Using the Uncontrolled Baseline Rate

CONTROL TECHNOLOGY	SO ₂ EMISSIONS (LB/MMBTU)	ANNUAL EMISSIONS (TONS)	INCREASE IN ANNUAL COST (\$)	ANNUAL AVERAGE COST (\$/TON)
Rectisol™	0.00585	149	19,797,825	94
Selexol™	0.0117	299	16,070,591	77
Uncontrolled	8.22	210,044	Baseline	Baseline

Table 4-10 Average Cost Effectiveness Using the Wabash Baseline Rate

CONTROL TECHNOLOGY	SO ₂ EMISSIONS (LB/MMBTU)	ANNUAL EMISSIONS (TONS)	INCREASE IN ANNUAL COST (\$)	ANNUAL AVERAGE COST (\$/TON)
Rectisol™	0.00585	149	19,797,825	5,126
Selexol™	0.0117	299	16,070,591	4,328
Wabash	0.157	4,012	Baseline	Baseline

Table 4-11 Average Cost Effectiveness Using the MDEA Baseline Rate

CONTROL TECHNOLOGY	SO ₂ EMISSIONS (LB/MMBTU)	ANNUAL EMISSIONS (TONS)	INCREASE IN ANNUAL COST (\$)	ANNUAL AVERAGE COST (\$/TON)
Rectisol™	0.00585	149	19,797,825	20,524
Selexol™	0.0117	299	16,070,591	19,715

MDEA	0.0436	1,114	Baseline	Base
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Energy Evaluation

Although additional energy requirements are associated with each of the acid gas recovery processes, Cash Creek concluded that their energy consumption is nominal when compared with balance of plant auxiliary power needs and does not warrant dismissing any of these processes from consideration as BACT.

Environmental Evaluation

Each of the Acid Gas Removal (AGR) methods evaluated in this BACT analysis involves a chemical process that uses a solvent to remove H₂S from syngas. Clean syngas from the AGR will be used as fuel in the combustion turbines. Each solvent used in the AGR will be regenerated and reused. Acid gases removed from the syngas will be processed to generate elemental sulfur in a sulfur recovery system. In each case, the AGR will generate a wastewater stream that must be processed prior to discharge. Cash Creek concluded that there are no unique collateral environmental issues that would preclude use of any of these AGR systems for SO₂ control as BACT.

Conclusion

Although no environmental or energy impacts favor one solvent AGR process over the other, the costs associated with the *Rectiso*TM system are significantly more than those for the *Selexo*TM system as compared with added reductions of SO₂ emissions. The *Rectiso*TM system has initial capital cost of approximately \$93 million and annual operating cost of almost \$11 million. The *Selexo*TM system has initial capital cost of about \$73 million and annual operating cost near \$9 million. Also, considering the average and incremental cost effectiveness of the alternatives, the *Selexo*TM system is the most attractive and results in emission rates lower than those achieved in practice at any currently operating IGCC, CFB, or pulverized coal boiler processing bituminous coal. Based on this information the *Rectiso*TM process is determined to be cost prohibitive to represent BACT for the project. Cash Creek determined that the *Selexo*TM process in combination with an SO₂ emission limit of 0.0117 lb/MMBtu, based on a 3-hr rolling average and an H₂SO₄ limit of 0.0026 lb/MMBtu based on a 3-hr rolling average represents BACT for Cash Creek's IGCC combustion turbines when firing syngas or natural gas. These emission limitations represent removal efficiencies greater than 99% and are greater than the efficiencies achieved in practice at currently operating IGCC units².

The Division concurs with the decision to use the *Selexo*TM process. As Cash Creek has noted, no IGCC facility currently operates with either a *Selexo*TM or *Rectiso*TM system, so actual costs are not available. In the absence of extensive operating experience, firm costs and vendor guarantees, the small difference in removal efficiencies and the cost difference between the two

² It should be noted that the Orlando Utility Commission & Southern Power Company's IGCC project in Orlando, Florida has a draft permit emission limit of 35.5 lb/hr (approximately 0.015 lb SO₂/MMBtu). See "Addendum to Technical Evaluation and Preliminary Determination dated July 26, 2006", at <http://www.dep.state.fl.us/Air/permitting/construction/oucsouthern.htm>.

systems are well within reasonable margins for error under these circumstances, and therefore, the relative cost -effectiveness of the systems are indistinguishable at this time.

4.5.3 OXIDES OF NITROGEN (IGCC)

NO_x control methods may be divided into combustion controls and post-combustion controls. Combustion NO_x controls reduce the NO_x generated and post-combustion NO_x controls remove NO_x by treating exhaust gases. A number of control options were listed in the application as follows:

Table 4-12 NO_x Emission Control Options

Control Method	Control Add-on Efficiency
Selective Catalytic Reduction (SCR)	60-90%
Diluent Injection	40-75%
Steam Injection	40-75%
Selective Non-Catalytic Reduction (SNCR)	40-70%

NO_x BACT Selection

Cash Creek selected SCR and nitrogen diluent to control NO_x emissions from the source. This combination of control processes with a NO_x emission limit of 0.0246 lb/MMBtu, based on a 24-hr rolling average represents BACT for the Cash Creek IGCC combustion turbines when firing syngas and natural gas. These emission limitations represent a removal efficiency of approximately 90%. This is lower than the emission achieved in practice at currently operating IGCC units and the lowest proposed emission limits for proposed coal-fired units, including other proposed IGCC units.

4.5.4 Carbon Monoxide (IGCC)

Carbon monoxide, a product of incomplete combustion, often results from achieving lower NO_x emissions. As stated earlier, the best methods for CO control is thermal oxidation and catalytic incineration. However, Cash Creek has indicated that neither technology is feasible for its units, but noted that a properly designed and operated combustion turbine effectively functions as a thermal oxidizer. When the temperature and excess oxygen availability are adequate for complete combustion CO formation is minimized. Minimization of the CO emitted is in the economical best interest of the operator because CO represents unutilized energy exiting the process. This is especially true in the case of IGCC since the primary energy component of syngas produced from gasification is CO.

CO emission rates are also identified as a potential factor that affects NO_x emissions on an inverse proportional basis (*i.e.*, lower CO tends to produce higher NO_x). Therefore any attempt to increase efficiency of the combustion turbines to reduce CO would potentially result in an increase in thermal NO_x emissions. Cash Creek concluded that based on the EPA's emphasis to reduce NO_x emissions, further reductions in CO emissions at the expense of increasing NO_x emissions are not warranted.

Carbon Monoxide BACT Selection

The applicant proposes proper operation and maintenance in combination

with an emission limit of 0.036 lb/MMBtu based on a 24-hour rolling average when firing syngas and 0.0449 lb/MMBtu, based on a 24-hour rolling average when firing natural gas, to be BACT for Cash Creek combustion turbines. This is supported by recent permits and applications for coal fired and IGCC projects.

Auxiliary Equipment Emissions

In addition to the combustion turbines, material handling equipment, and cooling towers, Cash Creek will have an auxiliary boiler and firewater pumps that will operate for a limited period of time each year.

Auxiliary Boiler

The 278.8 MMBtu/hr auxiliary boiler will be used to generate steam for start-up of the gasifiers. The steam is used to purge the gasifiers, provide pre-heat to the gasifier radiant syngas cooling section, and maintain temperature and pressure.

To minimize pollutant emissions, the auxiliary boiler will have low NO_x burners and fire natural gas. The auxiliary boiler will be restricted in hours of operation to less than 500 hours per year. The applicant is proposing proper boiler design and operation, low NO_x burners and use of natural gas to be BACT for the auxiliary boiler. BACT emissions limits for the auxiliary boiler are set out in Table 4-16.

Firewater Pumps

The proposed facility will be equipped with one electric and one natural gas-fired firewater pump for emergency fire protection. The natural gas fired pump will only be operated in case of an emergency and for short test periods.

The Applicant proposes to limit testing of the natural gas fire pump to less than 500 hours a year. This is similar to other sources in the Commonwealth of Kentucky. Therefore, the Applicant proposes limiting the hours of operation and use of natural gas to be BACT for the natural gas fire pump. BACT emissions limits for the natural gas fire pump are set out in Table 4-17. No emissions are expected from the electric fire pump.

Thermal Oxidizer And Flare

The proposed facility will use a flare for periods of startup, shutdown and malfunction. BACT may be no less stringent than a standard contained in 40 CFR 60 or 40 CFR 61. The Division has determined that upon review that BACT for PM and PM10 is compliance with the control requirements of 40 CFR 63.11. These are more stringent than the requirements in 40 CFR 60.18.

4.6 Step 5 - Select BACT

Tables 4-13 to 4-17 summarize the BACT determinations for Cash Creek's proposed IGCC combustion turbines, material handling, cooling towers, auxiliary boiler, and fire water pumps. All control technologies selected as BACT are supported by recent entries into the RBLC database, recently proposed applications, and/or other permits.

In addition, the various air quality dispersion-modeling analyses performed for Cash Creek demonstrate that criteria pollutant impacts from increased emissions fall below all NAAQS and PSD regulatory limits.

Table 4-13 BACT Determination for the Combustion Turbines

Pollutant	Emission Limit Based On C T Heat Input	Emission Limit Based On Gasifier Heat Input	Averaging Time	Control Technology
Firing Syngas				
PM/PM ₁₀	0.0085 lb/MMBtu	0.0063 lb/MMBtuU (filterable)	3-hour	Syngas Scrubbing
Filterable PM/PM ₁₀	0.0217 lb/MMBtu			
Total				
SO ₂	0.0158 lb/MMBtu	0.0117 lb/MMBtu	3-hour	Acid Gas Removal by physical absorption with Selexol solvent
NO _x	0.0331 lb/MMBtu	0.0246 lb/MMBtu	24-hour	SCR and Diluent N ₂ Injection
CO	0.0485 lb/MMBtu	0.036 lb/MMBtu	24-hour	Proper Combustion and Operation
H ₂ SO ₄	0.0035 lb/MMBtu	0.0026 lb/MMBtu	3-hour	Acid Gas Removal by physical absorption with Selexol solvent
Firing Natural Gas				
PM/PM ₁₀		0.0063 lb/MMBtu (filterable)	3-hour	Proper Combustion and Operation and Fuel Characteristics
SO ₂		0.00117 lb/MMBtu	3-hour	Proper Combustion and Operation and Fuel Characteristics
NO _x		0.0246 lb/MMBtu	24-hour	SCR and Diluent N ₂ Injection
CO		0.0449 lb/MMBtu	24-hour	Proper Combustion and Operation

Table 4-14 BACT Determination for Material Handling

Pollutant	Emission Source	Control Device
PM/PM ₁₀	Point Source	Enclosures Baghouses Vent Filters Fogging
	Fugitive Source Storage Pile and Operations	Compaction Suppressants Reduced Drop Heights Stacking Tubes
	Vehicles	Paved Roads Where Feasible Suppressants When Feasible Proper Road Maintenance

Table 4-15 BACT Determination for Cooling Tower

Pollutant	Emission Limit	Control Device
PM ₁₀ Drift	0.05 lb-drift/hr	0.0005% Drift Eliminators
VOC	TBD	Monitoring

Table 4-16 BACT Determination for Auxiliary Boiler

Pollutant	Emission Limit	Hours of Operation per year
PM/PM ₁₀	0.007 lb/MMBtu (filterable)	500
SO ₂	0.006 lb/MMBtu	500
NO _x	0.036 lb/MMBtu	500
CO	0.037 lb/MMBtu	500

Table 4-17 BACT Determination for Fire Pump

Pollutant	Emission Limit	Hours of Operation per year
PM/PM ₁₀	0.0019 lb/MMBtu (filterable)	500
SO ₂	0.0006 lb/MMBtu	500
NO _x	0.1 lb/MMBtu	500
CO	0.084 lb/MMBtu	500

By employing the selected technologies, Cash Creek will achieve emission rates that will be equal to or more stringent than the lowest emission rates for existing and proposed coal fired and IGCC generating units.

5. AIR QUALITY IMPACT ANALYSIS

Pursuant 401 KAR 51:017 Section 12, the applicant has provided an analysis of ambient air quality in the area that the proposed facility will affect for each regulated pollutant for which a NAAQS has been established and for which there will be a significant net emissions increase. The Division has not required the application to include an air quality impact analysis for ozone. Pursuant to 401 KAR 51:017 Section 7(5)(a), the Division may exempt a project that would result in a net emissions increase of less than 100 tpy of VOCs from an ambient air impact analysis, including the gathering of ambient air quality data.

The purpose of these analyses is to demonstrate that allowable emissions from the proposed project will not cause or contribute to air pollution in violation of:

- (1) A national ambient air quality standard in an air quality control region; or
- (2) An applicable increment over the baseline concentration in an area.

The proposed facility will have potential emissions in excess of the significant net emission rates for nitrogen oxides, carbon monoxide, sulfur dioxide, and PM₁₀. It should be noted that the steady-state normal operation of the proposed facility does not trigger a full impact air quality analysis of any of these pollutants. However, it is necessary to consider emissions during a cold start-up since this represents the worst case scenario for emissions. When considering start-up emissions, the only pollutant that is predicted to be above its Significant Impact Level is SO₂ for its 24-hr averaging period. Start up from a cold start takes approximately 48 hours and natural gas is used to preheat the unit during the first 33 hours and these emissions are vented to the Thermal Oxidizer. Start up modeling was used to determine the impacts of the second 24 hour period of start up. See Table 5 below for the emissions during the 48 hour start up period.

Table 5 Startup Emissions (Thermal Oxidizer modeled)

Pollutant	May 2006 Startup Emissions Lbs/hr	May 2006 Startup Emissions Tons/year
PM ₁₀	6.38*	27.94
CO	70.25	307.69
NO _x	117.0	512.46
SO ₂	200.88	879.85

* = Total PM₁₀ (includes condensable)

5.1 Modeling Methodology

The application for the proposed source contains AERMOD air dispersion modeling analysis for criteria pollutants (NO_x, SO₂, PM₁₀ and CO) to determine the maximum ambient concentrations attributable to the proposed plant for each of these pollutants for comparison with:

1. The significant impact levels (SIL) found in 40 CFR 51.165 (b)(2).
2. The Significant Air Quality Impact levels (SAI) found in Regulation 401 KAR 51:017, Section 7(5).
3. The PSD Class I and Class II increments found in Regulation 401 KAR 51:017, Section 2.
4. The National Ambient Air Quality Standards (NAAQS) found in Regulation 401 KAR 53:010, Ambient air quality standards.

All applicable ambient air quality concentration values are presented in Table 5-1. Based on U.S. EPA procedures, if the maximum predicted impacts for any pollutant are found to be below the SILs, then it is assumed that the proposed facility cannot cause or contribute to a violation of the PSD pollutant increments or the national ambient air quality standards (NAAQS). Therefore, no further modeling would be required for such a pollutant. The applicant may also be exempted from the ambient monitoring data requirements if the impacts are below the significant ambient impacts or SAI. The SAI levels determine if the applicant will be required to perform pre-construction monitoring. If the modeled impacts equal or exceed the SAI levels, pre-construction monitoring may be required. As shown in the application, the modeled impacts as compared to the SAI levels were not exceeded for, NO_x, CO, PM₁₀ and SO₂. All of the parameters used in the modeling analysis for each pollutant appear satisfactory and consistent with the prescribed usage for this model. See Sections 6, 7, and 9 of the permit application for details on meteorological, terrain, and land use/land cover (LULC) data selection and modeling methodology.

Therefore, applicant is exempted from the pre-construction ambient monitoring data requirements since the impacts are shown to be below the SAI.

Table 5-1 Ambient Air Quality Concentration Values

POLLUTANT	AVERAGING PERIOD	SIL ($\mu\text{g}/\text{m}^3$)	SAI ($\mu\text{g}/\text{m}^3$)	PSD CLASS II INCREMENTS ($\mu\text{g}/\text{m}^3$)	NAAQS ($\mu\text{g}/\text{m}^3$)
NO _x	Annual	1	14	25	100
PM ₁₀	Annual	1	NA	17	50
	24-HOUR	5	10	30	150
CO	8-hour	500	575	NA	10000
	1-hour	2000	NA	NA	40000
SO ₂	Annual	1	NA	20	80
	24-hour	5	13	91	365
	3-hour	25	NA	512	1300

The Division reviewed the air permit application and associated air dispersion modeling, determined the location of the existing monitors, quality of the data, and the data's correctness all met the requirements listed in the NSR guidance manual. Therefore, the applicant is exempted from the pre-construction ambient monitoring data requirements.

5.2 Modeling Results

5.2.1 Class II Area Impacts

As indicated below, the only pollutant that exceeds its Significant Impact Level is SO₂ for the 24-hour averaging period. No pollutants are predicted to exceed their respective Significant Ambient Impact.

TABLE 5-2 Applicants Modeled Predicted Impacts

POLLUTANT	AVERAGING PERIOD	SIL ($\mu\text{g}/\text{m}^3$)	SAI ($\mu\text{g}/\text{m}^3$)	MAX IMPACT OF EMISSION ($\mu\text{g}/\text{m}^3$)
NO ₂	Annual	1	14	0.438
PM ₁₀	Annual	1	NA	0.3085
	24-hour	5	10	3.99
SO ₂	Annual	1	NA	0.835
	24-hour	5	13	10.22
	3-hour	25	NA	21.14
CO	8-hour	500	575	37.99
	1-hour	2000	NA	61.69

As shown in the table below, the impact of SO₂ emissions will not cause a violation of the NAAQS or exceedance of the applicable increment.

Table 5-3 Refined Modeling Results

POLLUTANT	AVERAGING PERIOD	NAAQS ($\mu\text{g}/\text{m}^3$)	CLASS II PSD INCREMENT ($\mu\text{g}/\text{m}^3$)	MAX IMPACT – ALL SOURCES ($\mu\text{g}/\text{m}^3$)/INCREMENT CONSUMPTION
SO ₂	24-hour	365	91	150.28 20.20

Based on the analysis performed by the source, the emissions from the proposed source will not cause an exceedance of the NAAQS or a violation of the applicable Class II Increment.

5.2.2 Class I Area Impacts

The purpose of the Class I impact analysis is to predict the impacts of SO₂, PM₁₀, and NO_x emissions as well as the total deposition of nitrogen and sulfur, and the effect on visibility in Mammoth Cave National Park (MCNP). The park is 116 KM southeast of the proposed project and is designated as a Federal Class I area.

The CALPUFF modeling suite was used to predict concentrations in MCNP. Section 9 of the permit application entitled CLASS I ANALYSIS explains, in detail, the modeling methodology employed to estimate the impact on the park. The results (tables 9-8 and 9-9 of the application indicate the none of the applicable Significant Impact Levels will be exceeded. Therefore a cumulative analysis is not required pursuant to Federal guidance. The conclusion is that there will be no significant impact on the park due to the construction and operation of the proposed source.

Table 9-8: Class I Modeling Results – Normal Operations

	PROPOSED CLASS I SIL	1990	1992	1996
VISIBILITY CHANGE	RH_{max}	95.00%	95.00%	95.00%
24 HR MAX	5%	1.99	2.56	3.59
>5%		0	0	0
>10%		0	0	0
PM_{10 total} IMPACT - ug/m3				
24 HR MAX	0.2	0.0507	0.0652	0.0936
ANNUAL MAX	0.3	0.0036	0.0037	0.0040
SO₂ IMPACT - ug/m3				
3 HR MAX	1	0.1101	0.1278	0.1585
24 HR MAX	0.2	0.0338	0.0393	0.0519
ANNUAL MAX	0.1	0.0021	0.0021	0.0025
NO_x IMPACT - ug/m3				
ANNUAL MAX	0.1	0.0040	0.0037	0.0044
TOTAL S - ug/m2/s		5.29E-06	4.47E-06	7.45E-06
ANNUAL MAX	0.005 Kg/ha/yr	0.0017	0.0014	0.0023
BACKGROUND KG/HA/YR	16.99			
PERCENT CHANGE	%	0.010%	0.008%	0.014%
TOTAL N - ug/m2/s		5.48E-06	4.70E-06	6.22E-06
ANNUAL MAX	0.005 Kg/ha/yr	0.0017	0.0015	0.0020
BACKGROUND KG/HA/YR	20.65			
PERCENT CHANGE	%	0.008%	0.007%	0.009%
PM10 TOTAL ANALYSIS				
PMF				
24 HR MAX		3.60E-02	4.57E-02	6.37E-02
ANNUAL MAX		2.55E-03	2.61E-03	2.88E-03
EC				
24 HR MAX		3.61E-04	4.58E-04	6.39E-04
ANNUAL MAX		2.55E-05	2.62E-05	2.88E-05
SOA				
24 HR MAX		4.34E-03	5.52E-03	7.69E-03
ANNUAL MAX		3.07E-04	3.15E-04	3.47E-04
SO₄				
24 HR MAX		1.01E-02	1.36E-02	2.16E-02
ANNUAL MAX		7.09E-04	7.32E-04	7.71E-04
PM_{10(total)}				
24 HR MAX		5.075E-02	6.524E-02	9.362E-02
ANNUAL MAX		3.59E-03	3.69E-03	4.03E-03

Table 9-9: Class I Modeling Results – Startup

	PROPOSED CLASS I SIL	1996** STARTUP - INCREMENTAL
VISIBILITY CHANGE	RH_{max}	95.00%
24 HR MAX	5%	3.51
>5%		0
>10%		0
PM_{10 total} IMPACT - ug/m3		
24 HR MAX	0.2	0.0888
ANNUAL MAX	0.3	0.0021
SO₂ IMPACT - ug/m3		
3 HR MAX	1	0.4840
24 HR MAX	0.2	0.1197
ANNUAL MAX	0.1	0.0043
NO_x IMPACT - ug/m3		
ANNUAL MAX	0.1	0.0045
TOTAL S - ug/m2/s		8.85E-06
ANNUAL MAX	0.005 Kg/ha/yr	0.0028
BACKGROUND KG/HA/YR	16.99	
PERCENT CHANGE	%	0.016%
TOTAL N - ug/m2/s		5.02E-06
ANNUAL MAX	0.005 Kg/ha/yr	0.0016
BACKGROUND KG/HA/YR	20.65	
PERCENT CHANGE	%	0.008%
PM10 TOTAL ANALYSIS		
PMF		
24 HR MAX		5.53E-02
ANNUAL MAX		1.43E-03
EC		
24 HR MAX		5.49E-04
ANNUAL MAX		1.39E-04
SOA		
24 HR MAX		5.37E-03
ANNUAL MAX		1.35E-04
SO₄		
24 HR MAX		2.76E-02
ANNUAL MAX		3.48E-04
PM_{10(total)}		
24 HR MAX		8.882E-02
ANNUAL MAX		2.05E-03

6. ADDITIONAL IMPACTS ANALYSIS

401 KAR 51:017 Section 13 requires an applicant for a PSD permit to provide an analysis of the impairment to visibility, soils and vegetation that will occur as a result of the project and projected growth associated with the project.

6.1 Growth Analysis

As reported in the application, the proposed project will employ additional personnel that will peak at 1000 during the construction phase. The project will also employ 200-300 people on a permanent basis. It is a goal of the project to hire from the local community where possible. The proposed project is expected to result in an increase in residential and commercial growth in the vicinity of the plant. This increased economic activity will result in secondary air emissions (increased vehicular use) but is not expected to significantly impact air quality.

6.2 Soils and Vegetation Impacts Analysis

The proposed project is located on Kentucky State Highway 1078 in Henderson County. Impacts on the soil types and vegetation due to Cash Creek's air emissions were evaluated using EPA Document EPA-450/2-81-078 *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals*. Predicted ambient concentrations due to the project are below the NAAQS and PSD increments and no significant off-site impacts are expected from the proposed action. Therefore, the potential for adverse impacts to either soils or vegetation is minimal. It is concluded that no adverse impacts will occur to sensitive vegetation, crops or soil systems as a result of operation of the proposed project.

6.3 Visibility Impairment

The National Forest Service was contacted to identify Class II areas for visibility concerns. Ms. C. Huber by email dated May 11, 2005, wrote that "...No VISCREEN needed in this case. ... Land Between the Lakes National Recreation Area is managed by the National Forest Service, but it is over 50 km from Henderson County. ...so I would not ask that VISCREEN be done."

Thus, a Class II Visibility Analysis was not performed.

Section 7, ADDITIONAL IMPACT ANALYSIS, of the application contains a complete analysis of additional impact on soils and vegetation, secondary growth and Class II visibility that are all addressed in this section. The Division deems this analysis to be adequate to demonstrate that the construction and operation of the Cash Creek facility will not cause significant environmental impact.

7. CONCLUSIONS AND RECOMMENDATIONS

In conclusion, considering the information presented in the application, the Division has made a preliminary determination that the proposed project meets all applicable requirements:

1. All the emissions units are expected to meet the requirements of BACT for each significant pollutant. Additionally, each applicable emission limitation under 401 KAR Chapters 50 to 65 and each applicable emission standard and standard of performance under 40 CFR 60, 61 and 63 will also be met.

2. Ambient air quality impacts on Class II areas are expected to be below the significant impact levels. No adverse impact is expected on any Class I area.
3. Impacts on soil, vegetation, and visibility have been predicted to be minimal.

A draft permit to construct and operate a nominal 770 megawatt (MW) electric generating facility using Integrated Gasification Combined Cycle (IGCC) located southwest of Owensboro, Kentucky, in Henderson County, Kentucky containing conditions which may ensure compliance with all the applicable requirements listed above has been prepared by the Division and issued for public notice and comment. The Division recommends the issuance of the final permit following the public notice period, and after the resolution of any adverse comments received by the Division. A copy of this preliminary determination will be made available for public review at the following locations:

1. Henderson County Clerk's office, 20 N. Main St, Henderson, KY 42420.
2. Division for Air Quality, 803 Schenkel Lane, Frankfort.
3. Division for Air Quality, Owensboro Regional Office, 3032 Alvey Park Drive, Suite 700, Owensboro, KY 42303.